Public Information Forum
Sierra Nevada Region
January 25, 2011

Proposed Rates for the Central Valley & California/Oregon Transmission Projects, the Pacific Alternating Current Intertie & Path 15 Information

Public Information Forum
Sierra Nevada Region

Location:	Lake Natoma Inn, Folsom, CA 95630
Date/Time:	January 25, 2011, at 1:00 PM

Moderator:	Koji Kawamura
Presenter:	Charles J. Faust
Panel:	Steve Richardson
	Regina Rieger
	Juan Ortiz
	Padmini Palwe

Schedule of Proceedings

Major Milestones/Dates for SNR's Rate Case

- Western held 14 public informal rate meetings – June 2008 through April 2010
- Publish proposed rate adjustment FRN – January 3, 2011, begins 90-day consultation & comment period
- Public Information Forum – January 25, 2011
- Public Comment Forum – March 1, 2011
- Close of Comment Period – April 4, 2011
- Estimated Publish date for Final FRN – July 18, 2011
- Rates become effective on interim basis upon approval of Deputy Secretary – Deputy Secretary forwards the rate package to FERC for confirmation and approval
- Final rates become effective on interim basis – October 1, 2011 through September 30, 2016, or until superseded

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Proposed Rate Schedules

Formula Rate	Slide No.	Proposed Schedule
Transmission	**8**	
CVP Point-to-Point Transmission	**9**	CV-T3
CVP Network Integration Transmission Service (NITS)	**15**	CV-NWT5
COTP Point-to-Point Transmission	**16**	COTP-T3
PACI Point-to-Point Transmission	**21**	PACI-T3
Transmission of Western Power by Others	**25**	CV-TPT7
Unreserved Use Penalties	**26**	CV-UUP1
Ancillary Services	**30**	
Regulation and Frequency Response	**31**	CV-RFS4
Spinning/Supplemental Reserves	**34**	CV-SPR4, CV-SUR4
Energy Imbalance Service	**36**	CV-EID4
Generator Imbalance Service	**38**	CV-GID1
Power	**45**	
Base Resource and First Preference Power	**46**	CV-F13
▪ First Preference Revenue Requirement	**51**	CV-F13
▪ Maximum First Preference Allocation	**53**	CV-F13
▪ Base Resource Revenue Requirement	**55**	CV-F13
Custom Product Power	**58**	CPP-2
▪ Variable Resource Charge	**59**	CPP-2

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Changes to Proposed Rates since the Informal Rate Presentations

- The following Rates schedules are not changing:
  - COTP/PACI Transmission
  - Transmission by Others
  - Spinning and Supplement Reserves
  - Regulation and Frequency Response Service
  - Energy Imbalance Service
  - Custom Product Power
- CVP Transmission – Language change to Western ***may*** revise the rate v. Western ***will*** revise the rate

Changes to Proposed Rates since the Informal Rate Presentations

- Base Resource & First Preference – Billing clarification*
- New Services or Penalties
  - Generator Imbalance
    - Change to application of penalty for intermittent resources for under deliveries Western will charge the greater of actual or market price
  - Unreserved Use Penalties*
    - Change penalty from 150% to 200%
      - Consistency amongst Western's Regions
      - Consistent with FERC's *pro forma*

* Change since publication of 76 FR 127, January 3, 2011

Structure of Proposed Rates

- Component 1 → Formula Rate or Penalty
- Component 2 → Regulatory charges or credits passed through to relevant customer when possible or through Component 1
- Component 3 → Balance Authority charges or credits passed through to relevant customer when possible or through Component 1

Transmission Rates Section

Transmission	Slide No.	Rate Schedule
CVP Point-to-Point Transmission	**9**	CV-T3
CVP Network Integration Transmission Service (NITS)	**15**	CV-NWT5
COTP Point-to-Point Transmission	**16**	COTP-T3
PACI Point-to-Point Transmission	**21**	PACI-T3
Transmission of Western Power by Others	**25**	CV-TPT7
Unreserved Use Penalties	**26**	CV-UUP1

CVP Point-to-Point Transmission (CV-T3)

- Proposed Rate Schedule for the CVP firm and non-firm point to point transmission service
- Cost of Service Study
  - Allocates O&M, Interest and Depreciation between transmission and non-transmission.
  - Each CVP facility is researched to determine its functional use.
  - The cost for CVP facilities that supports the transfer capability of the transmission system are included in the transmission revenue requirement.
  - Costs for Facilities that support the generation capability are used to develop the Regulation Rate and Western's actual cost of generation.

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CVP Point-to-Point Transmission

Component 1:

$$\frac{\text{CVP TRR}}{\text{TTc + NITSc}}$$

- TRR = CVP transmission revenue requirement
- TTc = Transmission capacity under long term contract
- NITSc = 12-month average of the NITS customers usage at the time of the monthly CVP transmission coincident peak.
  - For rate design purposes, Western's use of the transmission system to meet its statutory obligations is treated as NITS.

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CVP TRR (Numerator)

TRR Comparison FY 2011 to Proposed FY 2012		
Cost Components in TRR	**Existing Rate** FY 2011 (in Millions)	**Proposed Rate** FY 2012 (in Millions)
Total TRR	$28.8	$37.3
•O&M	$25.2	$32.2
•Cost of Capital (Interest)	$ 1.1	$ 1.4
•Depreciation	$ 3.2	$ 4.4
•Credits (Short term sales, etc.)	($ 0.7)	($ 0.7)
Transmission Ratio	47.78%	59.54%

Increase is due to anticipated completion of assets supporting transmission function and not a rate methodology change.

CVP TTc and NITSc (Denominator)

TTc and NITSc Comparison FY 2011 to Proposed FY 2012		
Capacity	**Existing Rate** FY 2011 (in MW-mo.)	**Proposed Rate** FY 2012 (in MW-mo.)
Long Term Contracts (TTc)	533	659
Western's Use (NITSc)	1052	1052
NITS Customers (NITSc)	640	640
Total Capacity (TTc + NITSc)	2225	2351

CVP Transmission Existing and Proposed Rates

Transmission Rate Comparison FY 2011 to Proposed FY 2012		
Rate Type	**Existing Rate (FY 2011)**	**Proposed Rate (FY 2012)**
Transmission Revenue Requirement (in Millions)	$28.8	$37.3
Point-to-Point Rate ($/kW-mo.)	$1.08	$1.32
NITS Revenue Requirement (In Millions)	$21.9	$26.8
Increase is due to anticipated completion of assets supporting transmission function and not a rate methodology change.		

CVP Point-to-Point Transmission

- Rate ***may*** be revised based on either of the following conditions:
  - Updated financial data in March of each year; or
  - A change in the numerator or denominator that results in a rate change of at least $0.05 per kilowatt month.
- Language change from ***will*** to ***may*** is proposed to provide rate stability.
- We're soliciting feedback:
  - Considering the same language for COTP, PACI and Regulation

CVP Network Integrated Transmission Service (NITS) (CV-NWT5)

Component 1:

- NITS Revenue Requirement is the result of the CVP TRR less the CVP firm point-to-point TRR.
- Each NITS customer's allocation is based on the formula below:

NITS customer's monthly demand charge = NITS customer's load ratio share *times* 1/12 of the Annual Network TRR

COTP and PACI Point-to-Point Transmission

- COTP and PACI have three COI rating seasons:

  - Summer: June through October
  - Winter: November through March
  - Spring: April through May

- Rates will be updated and posted on OASIS at least 15 days before the start of each COI rating season.

COTP Point-to-Point Transmission (COTP-T3)

- California / Oregon Transmission Project is a jointly owned 342 mile, 500 KV transmission line that connects the Caption Jack Substation in southern Oregon to Tracy/Tesla Substation in California.

COTP Point-to-Point Transmission

Component 1:

$$\frac{\text{COTP TRR}}{\text{Western's Share of COTP Seasonal Capacity}}$$

- COTP TRR = Western's costs associated with facilities that support the transfer capability of the COTP.
- Western's Seasonal Capacity = Western's share of COTP capacity (subject curtailment) under the current COI transfer capability for the season.

COTP FY 2011

COTP FY 2011 Data for the Formula Rate Components	
Annual Tx Revenue Requirement (Numerator)	**Existing Rate FY 2011 (in Millions)**
O&M	$0.4
Cost of Capital (Interest)	$0.2
Depreciation	$0.55
Other Costs: COI Path Operator $0.2M Lease Capacity $0.5M	$0.7
Total Annual TRR	$1.85
Tx Revenue Requirement (Denominator)	**Existing Rate FY 2011**
Capacity	**77 MW-mo**

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COTP Seasonal Rates

COTP Rates for FY 2011 to FY 2012		
Season	**Existing Rate** **FY 2011 (in $/MWh)**	**Estimated Rates** **FY 2012 (in $/MWh)**
Winter (5 months)	**$2.77 current**	$2.83
Spring (2 months)	$2.74	$2.80
Summer (5 months)	$2.73	$2.79
Note: Seasonal rate determinations varies by cost & capacity allocation for the period being determined.		

PACI Point-to-Point Transmission (PACI-T3)

- Pacific Alternating Current Intertie: A 500 KV transmission project of which Western owns a portion of the facilities.

PACI Point-to-Point Transmission

Component 1:

$$\frac{\text{PACI TRR}}{\text{Western's PACI Seasonal Capacity}}$$

- PACI TRR = Western's costs associated with facilities that support the transfer capability of the PACI.
- Western's Seasonal Capacity = Western's share of PACI capacity (subject curtailment) under the current COI transfer capability for the season.

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PACI FY 2011

PACI FY 2011 Data for the Formula Rate Components	
Annual Tx Revenue Requirement (Numerator)	**Existing Rate FY 2011 (in Millions)**
O&M	$2.3
Cost of Capital (Interest)	$0.9
Depreciation	$0.3
Other Costs: COI Path Operator Cost	$0.5
Total Annual TRR	$4.0
Tx Revenue Requirement (Denominator)	**Existing Rate FY 2011**
Capacity	**400 MW-mo**

PACI Seasonal Rates

PACI Rates for FY 2011 to FY 2012		
Season	**Existing Rate FY 2011 (in $/MWh)**	**Estimated Rates FY 2012 (in $/MWh)**
Winter (5 months)	**$1.15 current**	$1.17
Spring (2 months)	$1.14	$1.16
Summer (5 months)	$1.13	$1.16

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Transmission of Western Power By Others (CV-TPT7)

Component 1:

- When Western uses transmission facilities other than its own to supply Western power, the benefitting customer will pay all costs for delivery of such power.

Other Information

- 100% pass through.
- Revenues and Expenses are included in the PRR.

Unreserved Use Penalties (CV-UUP1)

New

- Proposed Penalty Rate is ~~150~~ 200 percent of effective point-to-point transmission service rate.
  - Change penalty from 150% to 200%
    - Consistency amongst Western's Regions
    - Consistent with FERC's *pro forma*
- Penalty applicable when a transmission customer uses transmission service that:
  - Is not reserved or
  - Is in excess of reserved capacity

Unreserved Use Penalties

- *Exception:* Penalty will not apply as a result of actions taken to support reliability.
  - Such actions include reserve activations or uncontrolled event responses
- If ancillary services are used, the cost for such service will be recovered, but no penalty will be applied.
- Proceeds in excess of base rate will be distributed as a credit on future TRRs.

Unreserved Use Penalties - Example

Penalty assessed as follows:

- Single hour violation assessed at the daily rate
  - Ex (150% penalty): If daily rate is $35, charge is
    $35 + $17.50 = $52.50 per MW violation
  - Ex (200% penalty): If daily rate is $35, charge is
    $35 + $35 = $70 per MW violation
- More than one violation for given duration (e.g., daily) will increase to next longest duration (e.g., weekly)
- Multiple instances
  - Within a day = daily
  - Within one calendar week = weekly
  - Within more than one week = monthly

Transmission Rates Section

Discussion

&

Comments

Ancillary Services Rates Section

Ancillary Services	Slide No.	Rate Schedule
Regulation and Frequency Response	**31**	CV-RFS4
Spinning/Supplemental Reserves	**34**	CV-SPR4, CV-SUR4
Energy Imbalance Service	**36**	CV-EID4
Generator Imbalance Service	**38**	CV-GID1

Regulation and Frequency Response Service (CV-RFS4)

Component 1:

$$\frac{\text{Annual Revenue Requirement}}{\text{Annual Regulating Capacity (kW)}}$$

- Annual Revenue Requirement = the CVP generation costs associated with providing regulation.
- Annual Regulating Capacity = *one-half* of the total regulating capacity bandwidths provided by Western under Interconnected Operations Agreements with SBA customers.
- For a customer who self-provides and does not perform, will be assessed the greater of Western's actual cost or 150% of market.

Regulation Rate Calculation

FY 2011 Calculation of Regulation and Frequency Response Rate			
Step	**Line Description**	**Value**	**Reference or Calculation**
A.	Annual Cost of Generation	$83,382,503	Cost of Service Study
B.	Plant Capacity (kW)	1,500,277	CVP System Annual CP
C.	Cost/kW ($/kW-Year)	$65.48	A/B
D.	Regulation Capacity (kW)	27,000	Pursuant to IOAs
E.	Annual Regulation Revenue Requirement	$1,506,007	C x D
F.	Monthly Revenue Requirement	$125,501	E/12
G.	Rate $/kW-mo	**$4.65**	F/D

Regulation and Frequency Response Service (CV-RFS4)

- Rate will be revised based on either of the following conditions:
  - Updated financial data in March of each year; or
  - A change in the numerator or denominator that results in a rate change of at least $0.25 per kilowatt month.
- FY 2011 Regulation Rate: $4.65
- FY 2012 Regulation Rate: At time of review, threshold was not met. Rate will be reviewed in March 2011 and again prior to October 2011.

Spinning and Supplemental Reserves (CV-SPR4 & CV-SUR4)

- Assessed at the price consistent with the CAISO's market plus all costs incurred as a result of sales, such as Western's scheduling costs.

- For customers who have a contractual obligation to provide spinning or supplemental reserves, and do not fulfill the obligation, the penalty for non-performance will be the greater of actual cost or 150% of market cost.

Energy & Generator Imbalance

- For EI and GI, FERC Order No. 890 defined a three-tiered methodology.
- Since, Western has no customers subject to the provisions of GI, and Western's EI customers operate under existing agreements, both services will use the same methodology.
- Western will consider a transition to FERC's *pro forma* tariff methodology during its next rate process or earlier, if applicable.

Energy Imbalance (EI) Service (CV-EID4)

EI occurs when differences exist between scheduled and actual net energy. EI is applied to deviations as follows:

- For deviations within the bandwidth, there is no financial settlement; rather, deviations will be tracked and settled with energy;
- Negative deviations (under delivery), outside the bandwidth, charged the greater of 150 percent of market or actual cost; or
- Positive deviations (over delivery) outside the bandwidth, will be lost to the system.

Energy Imbalance (EI) Service

- Deviation bandwidths are established in the service agreement or Interconnected Operations Agreements (IOA).

- *Exceptions:*
  - Actions taken to support reliability, such as reserve activations or uncontrolled responses will be resolved in accordance with existing contractual requirements.

Generator Imbalance (GI) (CV-GID1)

New

- GI occurs when there is difference between scheduled and actual delivery of energy from an eligible generation resource within the SBA.
- GI is applied to deviations as follows:
  - For deviations within the bandwidth, there is no financial settlement; rather, deviations will be tracked and settled with energy;
  - Negative deviations (under delivery), outside the bandwidth, charged the greater of 150 percent of market or actual cost; or
  - Positive deviations (over delivery) outside the bandwidth, will be lost to the system.

Generator Imbalance (Example)

New

Generation Imbalance Service Charge Example Calculation (Component 1)	
If, on October 1, Hour Ending 1, Customer A has:	
Scheduled Generation Actual Generation	102 MW 90 MW
Scheduled in excess of Actual Generation (under delivery) Contractual Bandwidth	 12 MW 8 MW
Generator Imbalance for Hour Ending 1	4 MW

October 1, Hour Ending 1	Price	Price Comparison	MW	Charge
Western's Calculated Actual Cost	$18.27	Actual < 150% of Market	N/A	N/A
Real Time CAISO price ($21.84 * 150%) applied per rate schedule	$32.76	150% Market > Actual	4	$131.04
Note: GI charge for October 1, Hour Ending 1 is calculated as follows: 4 MW * $32.76 = $131.04				

Generator Imbalance (GI) Service

- Deviation bandwidths will be established in the service agreement or Interconnected Operations Agreements (IOA).
- *Exceptions*:
  - Actions taken to support reliability, such as reserve activations or uncontrolled responses will be resolved in accordance with existing contractual requirements;
  - Intermittent resources subject to deviations will not be assessed the 150% penalty, only cost.

Energy & Generator Imbalance

- For EI and GI, FERC Order No. 890 defined a three-tiered methodology.
- Since, Western has no customers subject to the provisions of GI, and Western's EI customers operate under existing agreements, both services will use the same methodology.
- Western will consider a transition to FERC's *pro forma* tariff methodology during its next rate process or earlier, if applicable.

Additional Items

Scheduling, System Control & Dispatch Service & Reactive Supply and Voltage Support

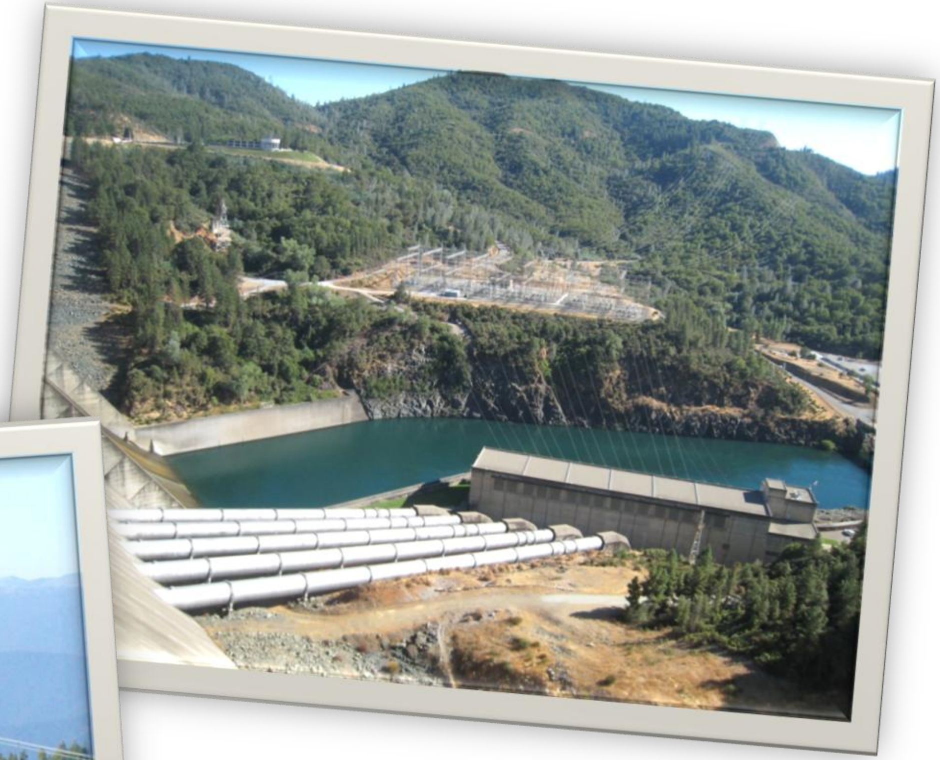
- Western's cost for Scheduling, System Control and Dispatch Service are included in the transmission revenue requirements for CVP, COTP, and PACI.
- FERC approved Rate Order No. WAPA-128 removed the costs for VAR Support Service from the transmission revenue requirements and included the cost in the BR and FP power rates. Western proposes no change.

Information on Path 15

- After completion in 2005, Western turned over the operational control of Western's Path 15 entitlements to the CAISO. Western maintains the lines and is compensated by Atlantic Path 15, LLC for the Operation and Maintenance work costs.
- Western does not charge a separate rate for Path-15.
- Western collects revenues from the CAISO under Amendment No. 48.
  - The CAISO pays Western for: wheeling, congestion, and Congestion Revenue Rights associated with Western's transmission rights on Path-15.

Ancillary Services Rates Section

Discussion & Comments



Power Section

Power	**Slide No.**	**Rate Schedule**
Base Resource and First Preference Power	**46**	CV-F13
•First Preference Revenue Requirement	**51**	CV-F13
•Maximum First Preference Allocation	**53**	CV-F13
•Base Resource Revenue Requirement	**55**	CV-F13
Custom Product Power	**58**	CPP-2
•Variable Resource Charge	**59**	CPP-2

Power Revenue Requirement (PRR)

- Prior to the start of each FY, Western will develop the PRR for the upcoming year.
- In March of each year, Western will review the PRR using actual and forecasted data.
- If the March review results in a change of $5 million or more, "~~the PRR for the April through September period will be recalculated.~~" Western will change the PRR applicable to the beginning of the FY. Clarification of application of rate schedule example is shown on slide 56.

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Power Revenue Requirement Allocation

PRR is allocated first to First Preference (FP) Customers based on their percentages then to Base Resource (BR) Customers.

Estimated FY 2012		
Component	**Formula**	**Allocation**
Annual PRR	PRR Model	$76,401,847
Total FP % = 4.77%	$76,401,847 x 4.77%	$ 3,644,368
Remaining PRR Allocated to BR	$76,401,847 – 3,644,368	$72,757,479

FY 2011 PRR Cost Components

Current FY 2011 PRR		
Cost Components in PRR	**Expenses**	**Revenues**
O&M (Western & BOR)	$92,506,493	
Purchase Power (inc. HBA costs)	$255,655,103	$251,018,028
Interest Expense	$6,460,533	
Other Expenses	$5,803,283	
Project Repayment	$12,500,000	
Other Pass-through	$38,637,920	$35,262,854
Other & Misc. Revenues		$28,630,520
Project Use Revenues		$20,900,000
Total Expenses & Revenues	$411,563,332	$335,811,403
Total PRR (FY 2011)	**$75,751,929**	

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FY 2012 PRR Cost Components

Estimated FY 2012 PRR		
Cost Components in PRR	**Expenses**	**Revenues**
O&M (Western & BOR)	$95,311,481	
Purchase Power (inc. HBA costs)	$264,181,411	$259,750,000
Interest Expense	$11,024,750	
Other Expenses	$3,903,283	
Project Repayment	$ 12,750,000	
Other Pass-through	$ 39,221,602	$ 36,275,284
Other & Misc. Revenues		$ 34,965,395
Project Use Revenues		$19,000,000
Total Expenses & Revenues	$426,392,527	$349,990,679
Total PRR (Estimated FY 2012)	**$76,401,847**	

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Current and *Projected* Power Revenue Requirements

SNR Power Revenue Requirements	
Fiscal Year	**PRR ($'s)**
2011 Current	75,751,929
Forecasted	
2012	*76,401,847*
2013	*76,442,738*
2014	*78,081,992*
2015	*78,967,580*

First Preference (FP) Formula Rate (CV-F13)

Component 1:

$$\text{FPC \%} = \frac{\text{FP Customer's Load}}{\text{(Gen + Power Purchases – Project Use)}}$$

- FP Customer's Load = Forecasted annual load (MWh)
- Gen = Forecasted annual CVP & Washoe generation (MWh)
- Power Purchases for Project Use & FP loads (MWh)
- Project Use = Forecasted annual Project Use load (MWh)

First Preference (FP) Formula Rate

- ❖ Western will develop each FP customer's percentage prior to each FY, and will review their percentages in March of each year.
- ❖ The March review will compare updated data to the initial estimate.
  - ❖ If the review results in a change in a FP customer's percentage of more than ½ of 1%, "the percentage will be revised for the ~~April-through-September period."~~ [entire FY.]
  - ❖ The results of the mid-year review will be applied to the revenue requirements for the entire FY.
- ❖ FP customers are billed in equal installments based on their percentage multiplied by the PRR.

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FP Maximum Percentage

- A FP customer's percentage cannot exceed the calculated maximum, except for increases due to load growth.
- Maximum percentages were primarily determined based on a critically dry year from the CVP Resources Report (Green Book).
- Maximum percentages remain in effect for this rate period or until superseded.

Estimated FY 2012 FP Percentages & Maximum

FP Customer	FP Estimated Percentage (FY12)	Maximum Percentage (Rate Period)
Sierra Conservation Center	**0.37**	**1.58**
Calaveras Public Power Agency	**0.90**	**3.81**
Trinity Public Utility District	**2.80**	**11.99**
Tuolumne Public Power Agency	**0.70**	**3.16**
Total	**4.77**	**20.54**

Base Resource (BR) Formula Rate (CV-F13)

Component 1:

BR Customer allocation = (BR RR x BR %)

- BR RR = Base Resource Monthly Revenue Requirement
- BR % = Base Resource Percentage for each customer as indicated in the BR contract after adjustments for programs, such as hourly exchange, if applicable.

- Western will continue to bill BR customers monthly based on 25% / 75% split
  - 25% during the first six months – October through March
  - 75% during the last six months – April through September
  - Changes at mid-year are applicable to the **entire FY**

BR and FP Billing Clarification

PRR Allocation to BR & FP: Initial & Mid-Year Adjustment					
	Oct - Mar		Apr - Sep		Required Collection for April - Sep
Power Revenue Requirement		**$75,000,000**		**$70,000,000**	
FP Percentages					
Customer A	0.60%	$450,000	0.60%	$420,000	$195,000
Customer B	1.00%	$750,000	1.00%	$700,000	$325,000
Customer C	3.00%	$2,250,000	2.48%	$1,736,000	$611,000
Customer D	0.40%	$300,000	0.40%	$280,000	$130,000
Total FP Rev Req (Annual)	5.00%	$3,750,000	4.48%	$3,136,000	$1,261,000
FP Paid During 6-mo Period		**$1,875,000**		**$1,261,000**	
BR Annual Rev Req (Annual)	$71,250,000		$66,864,000		$49,051,500
BR Paid During 6-mo Period		**$17,812,500**		**$49,051,500**	
Total PRR Collected		**$19,687,500**		**$50,312,500**	**$70,000,000**

~ This table is for illustration purposes only ~

Hourly Exchange (HE) Energy Program

Hourly Exchange Calculation								
Customer	**Assumed Contract BR %**	**BR RR ($75)**	**BR (MWh) (30)**	**Excess BR Load (EE)**	**Customer wanting EE (MWh)**	**BR delivered (adjusted to HE)**	**Revised BR %**	**Revised BR RR**
A	20	$15.00	6	3	0	3	10.00	$7.50
B	10	$7.50	3	0	1	4	13.33	$10.00
C	70	$52.50	21	0	2	23	76.67	$57.50
Total	100	$75.00	30	3	3	30	100	$75.00

Assumptions:
Base Resource RR is $75.
Customers A, B, and C are Full Load Service Customers.
Numbers may not calculate exactly due to rounding.

Custom Product Power (CPP) (CPP-2)

Customers who contract with Western to purchase supplemental power to meet load beyond BR.

- ❖ Purchases are made for a group of customers or for an individual customer.
- ❖ Revenue from surplus sales is prorated and distributed based on funding source and customer account status.
- ❖ All CPP costs are passed through to the customer.

Variable Resource (VR) Scheduling Charge

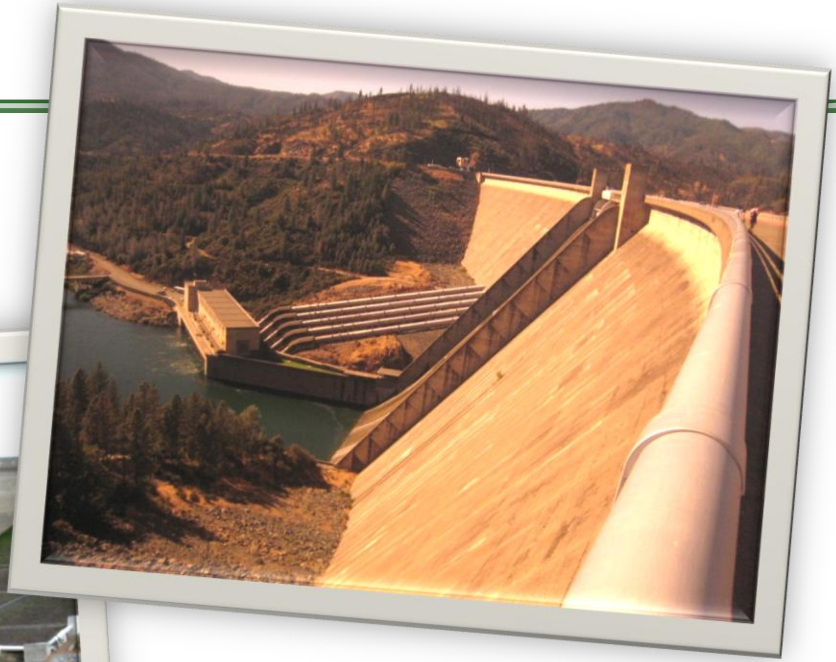
VR scheduling charges are based on O&M expenses and equipment, which are applied to VR customers requesting scheduling for CPP.

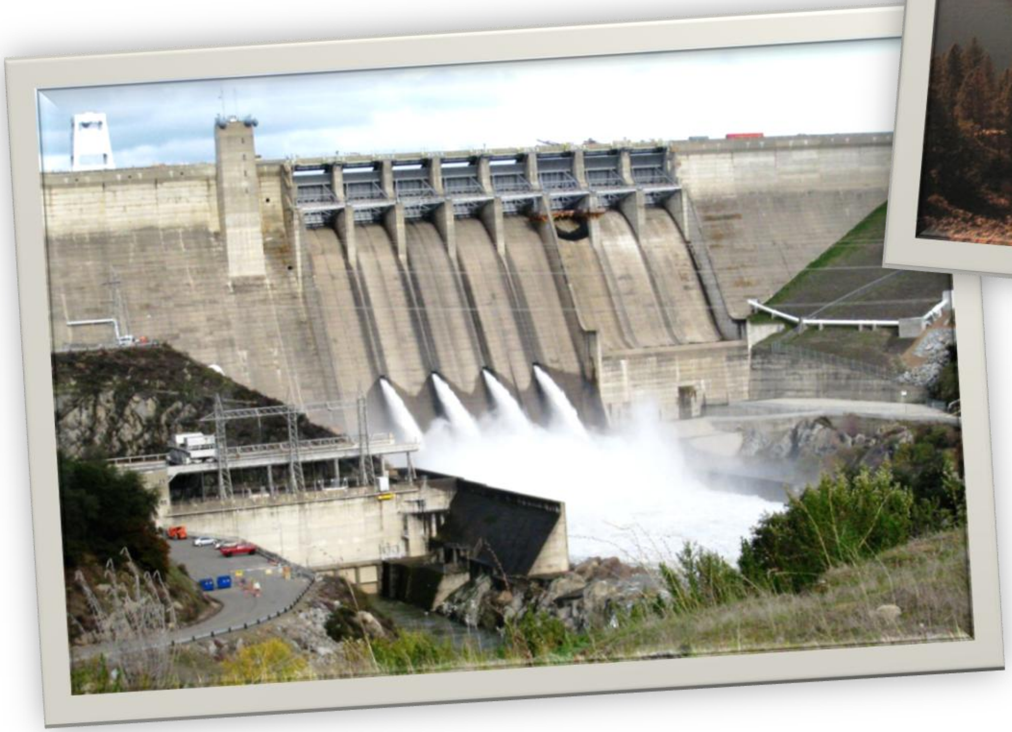
- VR customers pay a charge per schedule.
- FY 12 charge of $38.22 is a 23% increase over the existing rate of $31.07. The increase is based on the change in O&M between FY 05 and FY 10.
- FY 13 through FY 16 includes a 3% inflationary factor.

Variable Resource (VR) Scheduling Charge

Charge Per Schedule	
Fiscal Year	**Dollars ($)**
2005-2011	$31.07
2012	$38.22
2013	$39.36
2014	$40.54
2015	$41.76
2016	$43.01

Power Section





Discussion
&
Comments

Additional Comments

- Comments must be received by April 4, 2011, which is the end of the consultation and comment period.

Email: SNR-FY12RateCase@wapa.gov

Fax: (916) 985-1931

Mail: Western Area Power Administration
Sierra Nevada Region
114 Parkshore Drive
Folsom, CA 95630
Attention: Charles J. Faust

For Additional Information see our web link:
http://www.wapa.gov/sn/marketing/rates/